BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S APPLICATION FOR APPROVAL OF ITS CAPACITY DEFICIENCY PERIOD TO BE UTILIZED IN THE COMPANY'S SAR METHODOLOGY.	**CASE NO. IPC-E-13-21** **ORDER NO. 33016**

In Order No. 32697, the Commission directed that a case be initiated outside of each utility's Integrated Resource Plan (IRP) filing for the establishment of the capacity deficiency period to be utilized in the utility's SAR methodology. Idaho Power filed its 2013 IRP with the Commission on June 28, 2013. On November 4, 2013, Idaho Power filed this Application for approval of the capacity deficiency period to be utilized in the SAR avoided cost methodology. Idaho Power reports that its first deficit occurs in July 2021.

On November 26, 2013, the Commission issued a Notice of Application and set a deadline for intervention. Order No. 32933. J.R. Simplot Company petitioned for, and was granted, intervention. Order No. 32937. A Notice of Parties was issued on January 21, 2014. The parties agreed upon and proposed a procedural schedule for the processing of this case.

On January 24, 2014, the Commission issued a Notice of Modified Procedure and adopted the parties' proposed schedule. The Commission set a comment deadline of February 28, 2014, and a reply deadline of March 14, 2014. Order No. 32969. Staff and the Idaho Irrigation Pumpers Association, Inc., were the only people/parties to file comments. Idaho Power filed a reply.

By this Order, we approve July 2013 as Idaho Power Company's first capacity deficit to be utilized in the Company's SAR methodology as set out in more detail below.

THE APPLICATION

Idaho Power filed its 2013 IRP with the Commission on June 28, 2013. Idaho Power's 2013 IRP identifies the first peak-hour deficit occurring in July 2016. On October 15, 2013, Idaho Power filed updated components of the incremental cost IRP avoided cost methodology consisting of an updated load forecast, updated natural gas forecast, and updated list of new and terminated PURPA contracts and long-term power purchase agreements.

Applying the updated load and contract information with the 2013 IRP peak-hour deficits results in a first deficit for Idaho Power in July 2013.

On October 2, 2013, Idaho Power filed a settlement agreement regarding the continuation of its demand response programs. The Company maintains that updating its peak-hour deficits with up to 440 MW of capacity from the suspension of demand response programs results in the peak-hour deficits first occurring in July of 2021. Consequently, Idaho Power requests that the Commission approve July 2021 as the capacity deficiency period to be utilized in its SAR avoided cost methodology.

COMMENTS

Staff Comments

Staff did not dispute Idaho Power's IRP determination of its first peak-hour deficit or the effect of updated load and contract information on the Company's first deficit year. Staff did, however, oppose inclusion of 440 MW of demand response. Staff argued that inclusion of 440 MW of demand response assumes the Company can reliably and immediately provide 440 MW throughout the entire 20-year planning period. Staff stated that Idaho Power's position "contradicts the basis of the Commission-approved settlement agreement, the likely effect of the program modifications included in the settlement, and is not justified by the Company's responses to discovery in this case." Staff Comments at 4. Staff maintained that 170 MW would be the most reasonable estimate of capacity provided by Idaho Power's demand response.

Staff asserted that the effect of the October 2013 settlement terms on participation in the reinstated demand response programs is not yet known. However, Staff stated that the combination of reduced incentive payments, three mandatory annual dispatches, and reduced notification times will shrink the potential demand response capacity that existed prior to the settlement agreement. Staff based its calculation of 170 MW on the value of Idaho Power's demand response as used in the Company's demand response settlement. "Without demand response, the Company would likely build a 170 MW simple cycle combustion turbine (SCCT) to meet . . . short-term deficits and [the SCCT would] remain in the Company's resource portfolio through the life of the plant to meet future capacity deficits." Staff Comments at 5.

In support of including 170 MW of demand response, Staff further noted that current participation rates indicate that Idaho Power has approximately 30 MW of demand response remaining in its A/C Cool Credit Program. Staff also proposed including approximately 30 MW of commercial demand response.[1] Finally, Staff believed it reasonable to assume that irrigation participation would not fall more than two-thirds, or below approximately 110 MW, in the first year of the modified program.

Staff noted that Idaho Power's energy position does not affect the outcome of this case because the Company's capacity position is most critical in all years throughout the 20-year planning period. Therefore, Staff recommended approval of a 2016 first deficit year assumption for capacity.

Idaho Irrigators' Comments

The Idaho Irrigation Pumpers Association, Inc. ("Irrigators") filed public comments on March 14, 2014. The Irrigators oppose Staff's inclusion of only 170 MW of demand response in a determination of Idaho Power's capacity deficiency. The Irrigators claim that "higher avoided cost rates will be needed to be paid for new PURPA contracts to fill the capacity deficit that was caused by reducing the incentive paid to demand response participants." Irrigators Comments at 3. The Irrigators support use of the Company's proposal to use 440 MW of demand response in a determination of Idaho Power's capacity deficiency as it relates to rates using the SAR methodology. "Before using any value other than the 440 MW demand response figure, the Commission should wait until the 2015 IRP is released and Idaho Power has more experience with the new rates that went into effect for this coming summer." *Id.*

Idaho Power's Reply

Idaho Power filed reply comments on March 14, 2014. The Company argued that "Staff's arbitrary limitation of DR capacity to 170 MW" is inconsistent with the settlement agreement and would result in an overpayment of capacity in PURPA avoided cost rates to the detriment of customers. Reply at 3. Idaho Power stated that "Staff's position incorrectly equates the value (the amount the Company can spend on demand response) with the capacity (the amount of demand response the Company is required to accept)." *Id.* at 4.

Idaho Power conceded that participation in demand response programs subsequent to the settlement agreement is unknown. "A reduction in the amount of DR was anticipated in the Settlement Agreement due to a current lack of need for the amount of DR that had been attained in the past." *Id.* at 8. However, Idaho Power argued that, because it is required to accept up to

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[1]The settlement proposed and approved in IPC-E-13-14 requires Idaho Power to offer a commercial demand response program.

440 MW of demand response pursuant to the terms of the settlement, it is reasonable to include that amount in a consideration of capacity deficiency. Idaho Power maintained that Staff's recommendation is unreasonably low because "as customer load continues to grow and the need for increasing amount of DR returns, the Company anticipates incentive payment may need to be adjusted to attain program participation levels experienced in the past." *Id.* at 9.

Idaho Power stated that Staff's calculation regarding inclusion of 170 MW of demand response in the Company's assessment of capacity deficiency is arbitrary and without support. The Company encouraged the Commission to include 440 MW of demand response.

FINDINGS AND CONCLUSIONS

The Idaho Public Utilities Commission has jurisdiction over Idaho Power Company, an electric utility, and the issues raised in this matter pursuant to the authority and power granted it under Title 61 of the Idaho Code and the Public Utility Regulatory Policies Act of 1978 (PURPA). The Commission has authority under PURPA and the implementing regulations of the Federal Energy Regulatory Commission (FERC) to set avoided costs, to order electric utilities to enter into fixed-term obligations for the purchase of energy from qualified facilities (QFs) and to implement FERC rules.

The Commission has reviewed the record in this case, including Order No. 32697, Idaho Power's Application, and the comments of Commission Staff and the Irrigators, and reply of Idaho Power. In Case No. GNR-E-11-03, the Commission found it fair and reasonable to subject each utility's IRP determination of capacity deficiency to further scrutiny for purposes of use within the SAR methodology. Order No. 32697 at 23. The Company's 2013 IRP was filed with the Commission on June 28, 2013. The Commission accepted Idaho Power's 2013 IRP on February 24, 2014.

Idaho Power's 2013 IRP identifies that the Company's first peak-hour deficit occurs in July 2016. Updates based on load forecast, natural gas forecast, new and terminated PURPA contracts and long-term power purchase agreements results in the first deficit occurring in July 2013. These determinations of Idaho Power's first deficits are not disputed. The Company also proposed to include 440 MW of demand response which would delay a first deficit until July 2021.

Staff supports inclusion of only 170 MW of demand response resulting in a first deficit year of 2016. Staff's recommendation takes into consideration the untested and unforeseen effects of the demand response settlement agreement. The Irrigators support Idaho Power's proposal to include 440 MW of demand response in order to allow any potential benefits to inure to demand response participants and not unjustifiably inflate the capacity paid to new PURPA projects.

The Commission agrees with all of the parties and comments that the effect of demand response program changes is not yet known. Prior to the Company's 2013 suspension of demand response, Idaho Power reported having 437 MW of peak demand reduction potential. However, the settlement agreement reduces incentive payments, provides for three mandatory annual dispatches, and reduces notification times. Despite what the Company is required to accept in demand response pursuant to the terms of the settlement agreement, even Idaho Power expects reduced participation in its programs. It is unreasonable, then, to include 440 MW of demand response in a determination of capacity deficiency.

The recommendations of Commission Staff are equally subjective. Staff believes that some amount of demand response should be included in a determination of capacity deficiency, but must speculate on how much the demand response settlement will effect program participation.

Idaho Power made a business decision to suspend its demand response programs. As a consequence, demand response was not included as an existing resource in the Company's 2013 IRP. The terms and conditions of participation in these programs is now different and will result in differing levels of participation than what Idaho Power enjoyed prior to suspension. No one can determine participation levels with any degree of certainty. As we stated in the settlement proceedings, we continue to believe that "it is important for the Company to continue its DR programs to ensure it has sufficient, reliable DR resources to meet expected deficits." Order No. 32923 at 7. However, we decline to arbitrarily choose a number to attach to demand response for purposes of calculations within the SAR methodology absent evidence of the restructured programs' success. It is simply too early in the implementation process to be able to reasonably predict participation. Therefore, at this time, we cannot find a reasonable basis upon which to approve inclusion of any demand response in a determination of when Idaho Power becomes capacity deficient.

Based on the Company's IRP, updated load forecast, updated natural gas forecast, new and terminated PURPA contracts and long-term power purchase agreements, we find that

Idaho Power experiences its first capacity deficiency in July 2013. We find it fair and reasonable to direct the Company to utilize July 2013 for capacity deficiency to be used in the Company's SAR methodology. Consistent with these findings, we approve the SAR methodology avoided cost rates included as Attachment A to this Order. The Company will have an opportunity with its 2015 IRP to account for the restructured demand response potential and its corresponding impact on the utility's capacity deficiency.

ORDER

IT IS HEREBY ORDERED that Idaho Power utilize July 2013 as its first capacity deficit to be used in the Company's SAR methodology, as more fully described herein.

IT IS FURTHER ORDERED that the updated SAR avoided cost rates become effective upon issuance of this Order.

THIS IS A FINAL ORDER. Any person interested in this Order may petition for reconsideration within twenty-one (21) days of the service date of this Order. Within seven (7) days after any person has petitioned for reconsideration, any other person may cross-petition for reconsideration. See *Idaho Code* § 61-626.

DONE by Order of the Idaho Public Utilities Commission at Boise, Idaho this 8th day of April 2014.

PAUL KJELLANDER, PRESIDENT

MACK A. REDFORD, COMMISSIONER

MARSHA H. SMITH, COMMISSIONER

ATTEST:

Jean D. Jewell

IDAHO POWER COMPANY
AVOIDED COST RATES FOR WIND PROJECTS
April 8, 2014

$/MWh

New Contracts and Replacement Contracts without Full Capacity Payments

Eligibility for these rates is limited to projects 100 kW or smaller.

LEVELIZED

CONTRACT LENGTH (YEARS)	ON-LINE YEAR 2014	2015	2016	2017	2018	2019
1	31.94	33.28	38.22	40.85	44.28	46.72
2	32.58	35.65	39.49	42.50	45.46	47.66
3	34.32	37.25	40.96	43.80	46.45	48.91
4	35.76	38.81	42.24	44.88	47.61	50.32
5	37.21	40.15	43.33	46.04	48.91	51.65
6	38.50	41.31	44.47	47.29	50.17	52.73
7	39.64	42.47	45.67	48.51	51.22	53.65
8	40.76	43.66	46.84	49.54	52.13	54.46
9	41.92	44.82	47.85	50.45	52.95	55.17
10	43.03	45.83	48.75	51.27	53.66	55.85
11	44.01	46.73	49.56	51.99	54.34	56.52
12	44.90	47.55	50.28	52.67	55.00	57.17
13	45.70	48.27	50.96	53.33	55.65	57.84
14	46.42	48.96	51.62	53.98	56.30	58.51
15	47.10	49.62	52.26	54.61	56.96	59.20
16	47.75	50.25	52.88	55.26	57.63	59.93
17	48.37	50.87	53.51	55.91	58.32	60.70
18	48.98	51.49	54.14	56.58	59.06	61.51
19	49.58	52.11	54.79	57.29	59.83	62.36
20	50.18	52.73	55.47	58.02	60.64	63.24

NON-LEVELIZED

CONTRACT YEAR	NON-LEVELIZED RATES
2014	31.94
2015	33.28
2016	38.22
2017	40.85
2018	44.28
2019	46.72
2020	48.68
2021	51.73
2022	55.25
2023	58.20
2024	59.56
2025	60.99
2026	62.37
2027	63.36
2028	65.12
2029	67.09
2030	69.09
2031	71.58
2032	74.45
2033	77.47
2034	81.47
2035	86.49
2036	91.75
2037	97.20
2038	103.41
2039	107.10

Note: These rates will be further adjusted with the applicable integration charge.

Note: The rates shown in this table have been computed using the U.S. Energy Information Administration (EIA)'s Annual Energy Outlook 2013 released May 2, 2013. See "Annual Energy Outlook 2013, All Tables, Energy Prices by Sector and Source, Mountain, Reference case" at http://www.eia.gov/oiaf/aeo/tablebrowser/.

Attachment A
Order No. 33016
Case No. IPC-E-13-21

IDAHO POWER COMPANY
AVOIDED COST RATES FOR SOLAR PROJECTS
April 8, 2014
$/MWh
New Contracts and Replacement Contracts without Full Capacity Payments

Eligibility for these rates is limited to projects 100 kW or smaller.

LEVELIZED							NON-LEVELIZED	
CONTRACT LENGTH (YEARS)	ON-LINE YEAR						CONTRACT YEAR	NON-LEVELIZED RATES
	2014	2015	2016	2017	2018	2019		
1	58.36	60.08	65.41	68.44	72.28	75.12	2014	58.36
2	59.18	62.64	66.87	70.28	73.64	76.26	2015	60.08
3	61.10	64.42	68.53	71.77	74.83	77.71	2016	65.41
4	62.72	66.16	69.99	73.04	76.18	79.30	2017	68.44
5	64.35	67.68	71.26	74.38	77.67	80.83	2018	72.28
6	65.81	69.01	72.58	75.81	79.11	82.09	2019	75.12
7	67.11	70.35	73.95	77.20	80.33	83.19	2020	77.49
8	68.40	71.71	75.29	78.41	81.42	84.18	2021	80.96
9	69.72	73.03	76.47	79.49	82.41	85.06	2022	84.92
10	70.99	74.19	77.53	80.47	83.29	85.91	2023	88.30
11	72.12	75.25	78.50	81.35	84.13	86.75	2024	90.09
12	73.16	76.22	79.37	82.19	84.95	87.56	2025	91.97
13	74.11	77.09	80.21	83.00	85.76	88.38	2026	93.81
14	74.97	77.93	81.01	83.79	86.56	89.21	2027	95.25
15	75.79	78.72	81.79	84.58	87.36	90.05	2028	97.48
16	76.57	79.49	82.55	85.36	88.17	90.92	2029	99.93
17	77.33	80.25	83.32	86.15	89.01	91.83	2030	102.41
18	78.06	81.00	84.08	86.95	89.88	92.78	2031	105.38
19	78.79	81.74	84.85	87.79	90.78	93.76	2032	108.75
20	79.51	82.49	85.65	88.65	91.71	94.77	2033	112.27
							2034	116.78
							2035	122.32
							2036	128.11
							2037	134.09
							2038	140.84
							2039	145.09

Note: These rates will be further adjusted with the applicable integration charge.

Note: The rates shown in this table have been computed using the U.S. Energy Information Administration (EIA)'s Annual Energy Outlook 2013 released May 2, 2013. See "Annual Energy Outlook 2013, All Tables, Energy Prices by Sector and Source, Mountain, Reference case" at http://www.eia.gov/oiaf/aeo/tablebrowser/.

IDAHO POWER COMPANY
AVOIDED COST RATES FOR NON-SEASONAL HYDRO PROJECTS
April 8, 2014
$/MWh
New Contracts and Replacement Contracts without Full Capacity Payments

Eligibility for these rates is limited to projects smaller than 10 aMW.

LEVELIZED							NON-LEVELIZED	
CONTRACT LENGTH (YEARS)	ON-LINE YEAR						CONTRACT YEAR	NON-LEVELIZED RATES
	2014	2015	2016	2017	2018	2019		
1	55.79	57.48	62.77	65.76	69.56	72.37	2014	55.79
2	56.60	60.02	64.21	67.59	70.91	73.48	2015	57.48
3	58.50	61.79	65.85	69.06	72.07	74.91	2016	62.77
4	60.11	63.51	67.29	70.30	73.41	76.49	2017	65.76
5	61.71	65.01	68.55	71.63	74.88	78.00	2018	69.56
6	63.16	66.32	69.85	73.04	76.30	79.24	2019	72.37
7	64.44	67.64	71.21	74.42	77.51	80.32	2020	74.69
8	65.72	68.98	72.53	75.61	78.58	81.30	2021	78.12
9	67.02	70.29	73.69	76.67	79.55	82.16	2022	82.04
10	68.27	71.44	74.74	77.63	80.41	82.99	2023	85.38
11	69.40	72.48	75.69	78.50	81.24	83.81	2024	87.13
12	70.42	73.44	76.55	79.32	82.05	84.61	2025	88.96
13	71.35	74.30	77.37	80.12	82.83	85.42	2026	90.76
14	72.20	75.11	78.16	80.90	83.62	86.23	2027	92.16
15	73.00	75.90	78.92	81.67	84.41	87.05	2028	94.34
16	73.77	76.66	79.67	82.44	85.21	87.91	2029	96.74
17	74.52	77.40	80.42	83.21	86.03	88.81	2030	99.18
18	75.24	78.13	81.17	84.00	86.89	89.75	2031	102.10
19	75.95	78.86	81.93	84.83	87.78	90.71	2032	105.42
20	76.66	79.60	82.72	85.68	88.70	91.71	2033	108.89
							2034	113.35
							2035	118.84
							2036	124.58
							2037	130.51
							2038	137.21
							2039	141.40

Note: The rates shown in this table have been computed using the U.S. Energy Information Administration (EIA)'s Annual Energy Outlook 2013 released May 2, 2013. See "Annual Energy Outlook 2013, All Tables, Energy Prices by Sector and Source, Mountain, Reference case" at http://www.eia.gov/oiaf/aeo/tablebrowser/.

IDAHO POWER COMPANY
AVOIDED COST RATES FOR SEASONAL HYDRO PROJECTS
April 8, 2014

$/MWh

New Contracts and Replacement Contracts without Full Capacity Payments

Eligibility for these rates is limited to projects smaller than 10 aMW.

LEVELIZED

CONTRACT LENGTH (YEARS)	ON-LINE YEAR 2014	2015	2016	2017	2018	2019
1	73.76	75.71	81.27	84.53	88.60	91.69
2	74.70	78.38	82.84	86.49	90.08	92.94
3	76.72	80.27	84.61	88.09	91.38	94.50
4	78.45	82.12	86.18	89.46	92.85	96.21
5	80.17	83.74	87.56	90.91	94.44	97.85
6	81.74	85.17	88.98	92.45	95.99	99.21
7	83.14	86.61	90.45	93.94	97.32	100.42
8	84.53	88.06	91.89	95.25	98.51	101.52
9	85.93	89.48	93.16	96.42	99.59	102.50
10	87.30	90.74	94.32	97.50	100.57	103.45
11	88.52	91.89	95.38	98.47	101.51	104.38
12	89.64	92.94	96.34	99.41	102.42	105.29
13	90.68	93.91	97.26	100.31	103.32	106.20
14	91.62	94.82	98.15	101.19	104.20	107.12
15	92.52	95.70	99.01	102.06	105.10	108.04
16	93.38	96.55	99.86	102.92	105.99	108.99
17	94.21	97.38	100.70	103.79	106.90	109.99
18	95.02	98.21	101.54	104.67	107.86	111.02
19	95.82	99.02	102.39	105.58	108.84	112.08
20	96.61	99.84	103.26	106.52	109.84	113.16

NON-LEVELIZED

CONTRACT YEAR	NON-LEVELIZED RATES
2014	73.76
2015	75.71
2016	81.27
2017	84.53
2018	88.60
2019	91.69
2020	94.30
2021	98.01
2022	102.22
2023	105.85
2024	107.90
2025	110.04
2026	112.15
2027	113.86
2028	116.36
2029	119.08
2030	121.85
2031	125.10
2032	128.76
2033	132.57
2034	137.38
2035	143.22
2036	149.32
2037	155.61
2038	162.68
2039	167.24

Note: A "seasonal hydro project" is defined as a generation facility which produces at least 55% of its annual generation during the months of June, July, and August. Order 32802.

Note: The rates shown in this table have been computed using the U.S. Energy Information Administration (EIA)'s Annual Energy Outlook 2013 released May 2, 2013. See "Annual Energy Outlook 2013, All Tables, Energy Prices by Sector and Source, Mountain, Reference case" at http://www.eia.gov/oiaf/aeo/tablebrowser/.

IDAHO POWER COMPANY
AVOIDED COST RATES FOR OTHER PROJECTS
April 8, 2014
$/MWh
New Contracts and Replacement Contracts without Full Capacity Payments

Eligibility for these rates is limited to projects smaller than 10 aMW.

LEVELIZED							NON-LEVELIZED	
CONTRACT LENGTH (YEARS)	ON-LINE YEAR						CONTRACT YEAR	NON-LEVELIZED RATES
	2014	2015	2016	2017	2018	2019		
1	48.83	50.41	55.61	58.50	62.18	64.88	2014	48.83
2	49.59	52.91	56.99	60.27	63.48	65.95	2015	50.41
3	51.44	54.63	58.59	61.69	64.59	67.32	2016	55.61
4	53.00	56.30	59.98	62.89	65.88	68.85	2017	58.50
5	54.56	57.76	61.19	64.17	67.30	70.31	2018	62.18
6	55.96	59.03	62.44	65.53	68.68	71.50	2019	64.88
7	57.20	60.30	63.76	66.86	69.84	72.54	2020	67.10
8	58.44	61.60	65.04	68.00	70.86	73.47	2021	70.42
9	59.69	62.86	66.15	69.02	71.78	74.28	2022	74.22
10	60.91	63.97	67.16	69.94	72.60	75.07	2023	77.45
11	61.99	64.97	68.07	70.76	73.39	75.85	2024	79.08
12	62.97	65.88	68.88	71.55	74.16	76.61	2025	80.80
13	63.87	66.70	69.66	72.31	74.90	77.37	2026	82.48
14	64.68	67.48	70.41	73.04	75.65	78.14	2027	83.75
15	65.45	68.23	71.14	73.78	76.40	78.93	2028	85.82
16	66.18	68.95	71.86	74.51	77.16	79.74	2029	88.09
17	66.89	69.66	72.57	75.24	77.94	80.61	2030	90.40
18	67.58	70.36	73.28	76.00	78.77	81.51	2031	93.19
19	68.26	71.05	74.01	76.79	79.63	82.44	2032	96.39
20	68.93	71.76	74.77	77.61	80.51	83.40	2033	99.72
							2034	104.05
							2035	109.40
							2036	115.00
							2037	120.79
							2038	127.35
							2039	131.39

Note: "Other projects" refers to projects other than wind, solar, non-seasonal hydro, and seasonal hydro projects. These "Other projects" may include (but are not limited to): cogeneration, biomass, biogas, landfill gas, or geothermal projects.

Note: The rates shown in this table have been computed using the U.S. Energy Information Administration (EIA)'s Annual Energy Outlook 2013 released May 2, 2013. See "Annual Energy Outlook 2013, All Tables, Energy Prices by Sector and Source, Mountain, Reference case" at http://www.eia.gov/oiaf/aeo/tablebrowser/.